CALIFORNIA
ENERGY
COMMISSION

STAFF FORECAST OF 2007 PEAK DEMAND

DRAFT STAFF REPORT

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Introduction and Background

This document describes staff's proposed updated 2007 peak demand forecasts for the territories of the three investor-owned utility (IOUs), Pacific Gas and Electric (PG&E), Southern California Edison (SCE), and San Diego Gas & Electric (SDG&E). A revised ten-year forecast for the IOUs, as well as a revised forecast for the rest of the state, will be developed as part of the 2007 *Integrated Energy Policy Report* (*Energy Report*). The primary purpose of this updated 2007 peak forecast is to provide a reference case for the California Public Utilities Commission's (CPUC) resource adequacy process.

The CPUC determined in their resource adequacy proceeding that the Energy Commission demand forecast, as the "state's official load forecast," should serve as the reference case in the resource adequacy load forecast review and adjustment process which is implemented by Energy Commission staff.[1] If the sum of the year-ahead forecasts submitted by load serving entities (LSEs) is more than one percent different than the Energy Commission forecast, staff adjusts the LSE forecasts to within one percent, as directed by the CPUC. These adjusted forecasts must be used in the LSE's year-ahead compliance filing with the CPUC in which they demonstrate that they have contracted in advance for ninety percent of their forecasted peak demand. For the 2006 forecasts, a small increase was necessary.

The September 2005 forecast, prepared for the 2005 *Energy Report*, is the most recent adopted Energy Commission forecast.[2] This forecast was based on actual historic energy consumption and peak demand through the year 2004. To establish a peak forecast for the 2007 resource adequacy process, staff evaluated the 2005 recorded loads and temperature data and analyzed how much that forecast should be revised.

Summary of Results

To develop the 2007 peak demand forecast, staff first estimated the relationship between temperature and daily summer peak demand for each service area. This estimated equation was applied to historic average of annual maximum temperatures to derive an estimate of weather-adjusted demand for 2005. Finally, the growth rate from the September 2005 demand forecast was used to produce a revised annual peak forecast for 2007.

Table 1 shows the results of this analysis. The 2005 column shows the estimates of the weather adjusted peaks compared to the forecast. The 2007 column compares the September 2005 forecast with the proposed revised forecast. For all three areas, the weather adjusted peak is significantly higher than originally projected. As a result, the revised 2007 forecasts for PG&E and SCE are more than four percent higher than the September 2005 forecast of 2007, while the SDG&E forecast increases by 1.8 percent.

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Table 1: Revised versus September 2005 Peak Demand Forecast Megawatts (MW)

		2005	2007	Annual Growth Rate
PG&E Service Area	**Sept. 2005 *Energy Report* Forecast**	18,311	18,914	1.6%
	Revised Forecast	19,272	19,905	1.6%
	Change	961	991	
SCE Planning Area	**Sept. 2005 *Energy Report* Forecast**	21,510	22,163	1.5%
	Revised Forecast	22,442	23,124	1.5%
	Change	932	960	
SDG&E	**Sept. 2005 *Energy Report* Forecast**	4,231	4,371	1.6%
	Revised Forecast	4,307	4,450	1.6%
	Change	76	79	

The revised forecast of 2007 will be applied to hourly forecast load shapes from the IOUs to develop a monthly peak forecast for each service area. For SCE, whose Federal Energy Regulatory Commission (FERC) Form 714 hourly loads include non-CPUC jurisdictional LSEs, staff will use historic loads for individual LSEs (from both FERC Form 714 and California Independent System Operator hourly settlement data) to disaggregate the planning area peak forecast into SCE service area and publicly owned utility components.

The remainder of this document describes the methodology and data used for each utility forecast, followed by a discussion of possible sources of forecast error.

General Weather Normalization Methodology

Staff used preliminary 2005 FERC Form 714 hourly load data and utility planning area daily temperatures to estimate the relationship between the summer weekday afternoon (1 PM-6 PM) peak and temperatures. Summer is defined to be the period from June 15 to September 15 for this analysis. The temperature variable for each utility is a weighted average of temperatures from a set of weather stations that are representative of the climate in that utility region (Table 2). The weights are based on the estimated number of residential air conditioning units in each of the utility forecast zones as assumed in the Energy Commission residential demand forecast model.

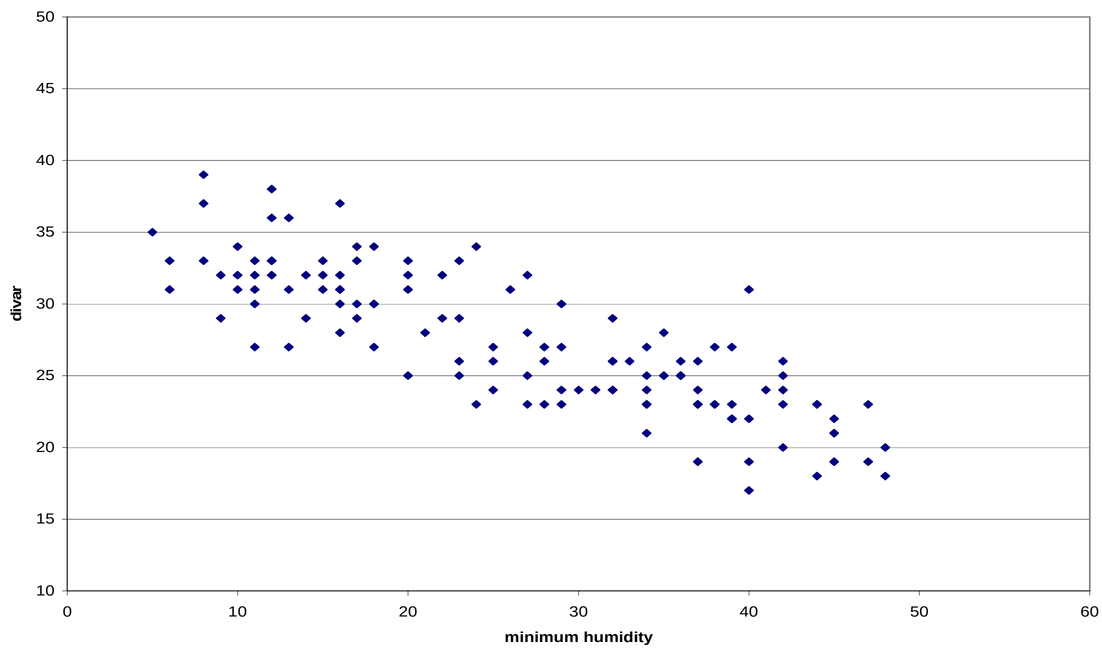
Table 2: Planning Area Weather Weighting Factors

Utility	**Station/Weight**				
PG&E	**Ukiah**	**Sacramento**	**Fresno**	**San Jose**	**San Francisco**
	0.072	0.144	0.422	0.325	0.037
SCE	**Fresno**	**Long Beach**	**Burbank**	**Riverside**	
	0.062	0.324	0.243	0.371	
SDG&E	**Lindbergh Field**	**Mirimar**	**El Cajon**		
	0.333	0.333	0.0333		

Two separate weather variables were calculated for this analysis. The first is a weighted average of maximum temperatures on three days (*max631*). The weighting consists of 60 percent of the current day's maximum temperature, 30 percent of the previous day's maximum and 10 percent of the second previous day's maximum. The lag is used to account for heat build-up over a three day period. The "1-in-2" or normal peak temperature is the median annual maximum temperature, over the 1950-2005 period, for PG&E and SCE. The time period used for the SDG&E planning area was limited to 1979-2005 because daily weather data is not continuously available for El Cajon prior to 1979.

The daily temperature spread, or diurnal variation (*divar*) is the second temperature variable. This variable is the daily maximum temperature minus the daily minimum temperature. It serves as a proxy measure of daily humidity. The assumption is that the lower the daily temperature spread for a given temperature, the higher the daily humidity (i.e. a day with a maximum temperature of 95 degrees Fahrenheit (deg F) and a minimum of 75 deg F is likely to be more humid than a day with a maximum temperature of 95 deg F and a minimum temperature of 65 deg F). This proxy is used because there is little historic information available for long time periods on humidity for most weather stations, while daily maximum and minimum temperatures are readily available. Figure 1 shows the relationship between daily diurnal variation and minimum humidity for Burbank on days which the maximum temperature was 80 deg F or above.

Figure 1: Daily Minimum Humidity and Diurnal Variation
(Burbank 2005 daily maximum temperature 80 or above)

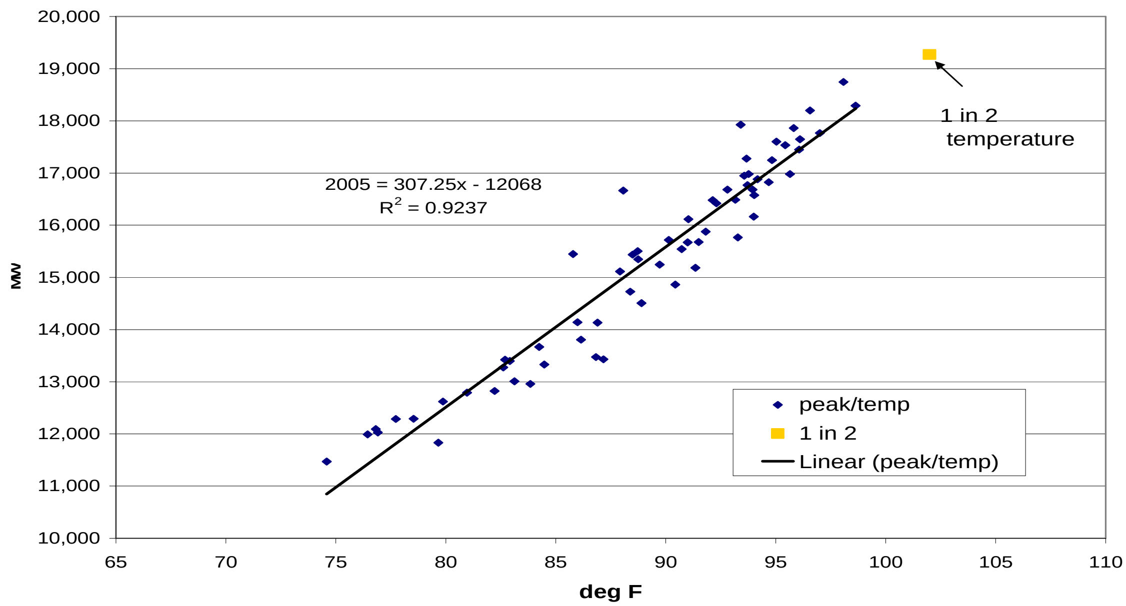


This variable was developed because of abnormally high humidity from the remnants of hurricane Emily, which dissipated westward along the U.S.-Mexico border and into southern California and drove, in part, the 2005 southern California peak. Emily caused increased humidity relative to normal weather patterns, primarily in the SCE service area with a minor impact in the SDG&E service area. The daily diurnal variation is not lagged because it is intended to provide a measurement of the actual daily humidity which impacts the physical need for air conditioning compressors to take water vapor out of the air.

PG&E Service Area Results

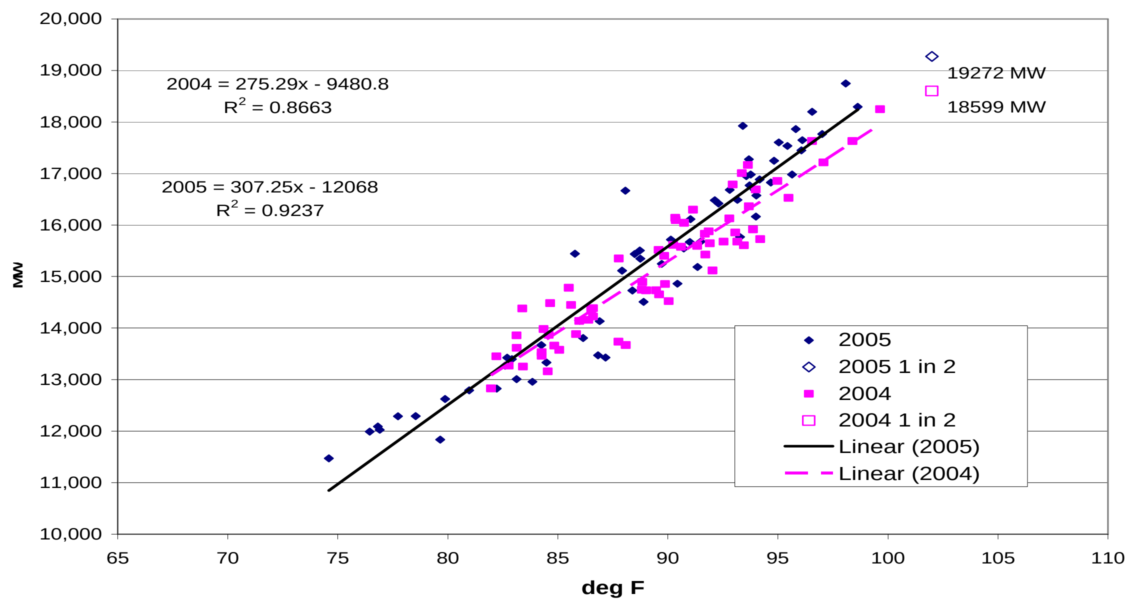
Figure 2 presents the 2005 weekday peak and *max631* relationship for the summer weekday period (June 15th through September 15th) for the PG&E service area. Also shown is the estimated peak (19,272 MW) at the 1-in-2 temperature (102 deg F) assumed for the PG&E planning area. The weather normalized peak assumes that the peak/temperature relationship estimated from the below average temperatures experienced in the summer of 2005 is also valid at 1-in-2 temperatures.

Figure 2: PG&E 2005 Summer Weekday Peaks vs. Temperature



The summer weekday peaks for 2004 and 2005 and the weather normalized peak values for each year are compared in Figure 3. The 2005 summer temperatures were more widely dispersed than those in 2004.

Figure 3: PG&E 2004 – 2005 Summer Weekday Temperature-Peak Comparison



SCE Planning Area Results

A combination of high temperatures and abnormally high humidity caused the 2005 peak demand in the SCE planning area. Staff investigated two models for weather normalization. The first model considered lagged temperature only and the second considered both lagged temperature and daily diurnal variation as a proxy for humidity as described above. Figure 4 presents the predicted and actual results of both models. Adding diurnal variation as an explanatory variable increased the R^2 from 0.87 to 0.91.[3]

Figure 4: Predicted SCE Weekday Peaks Using Temperature and Diurnal Variation

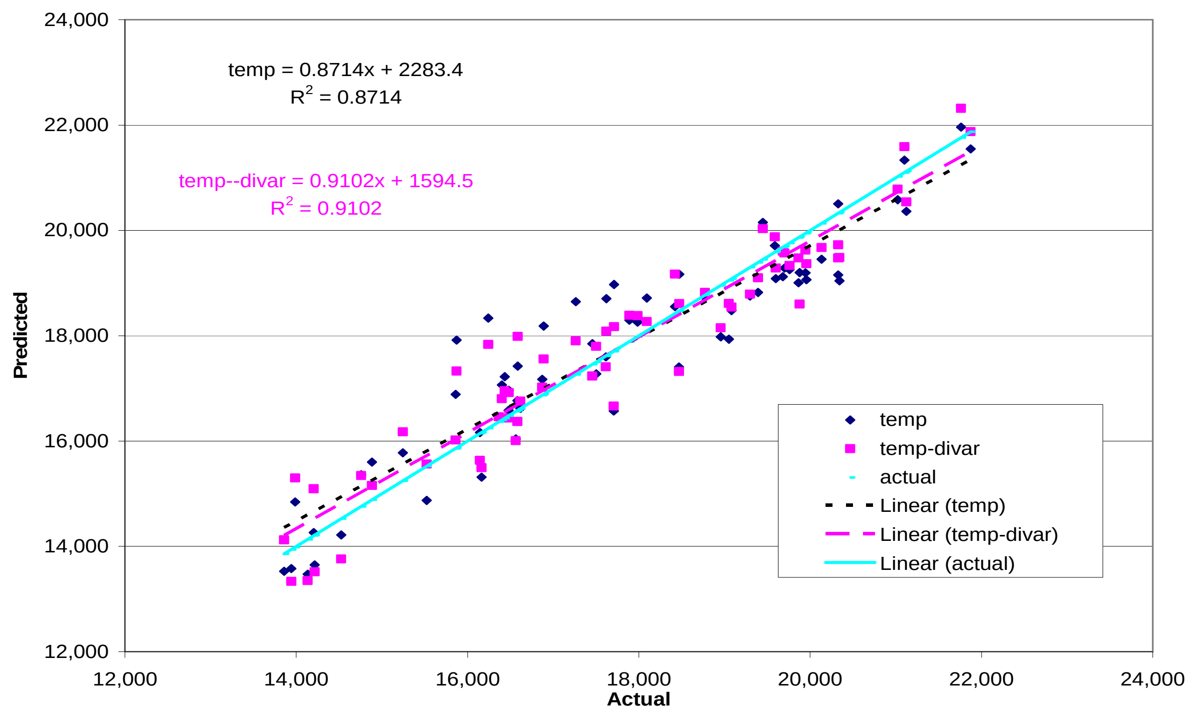
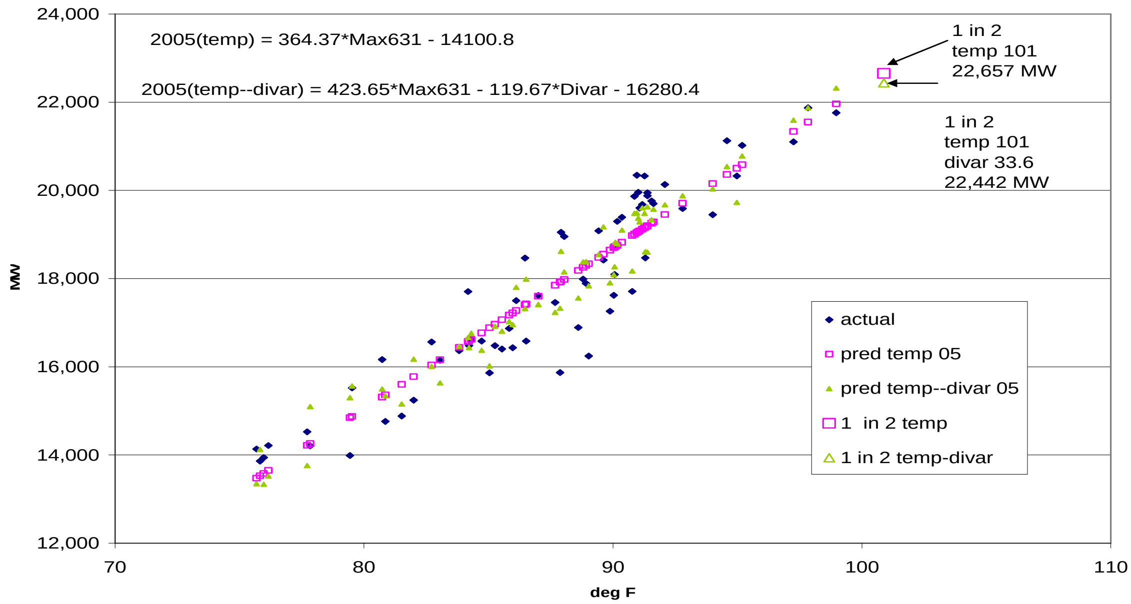


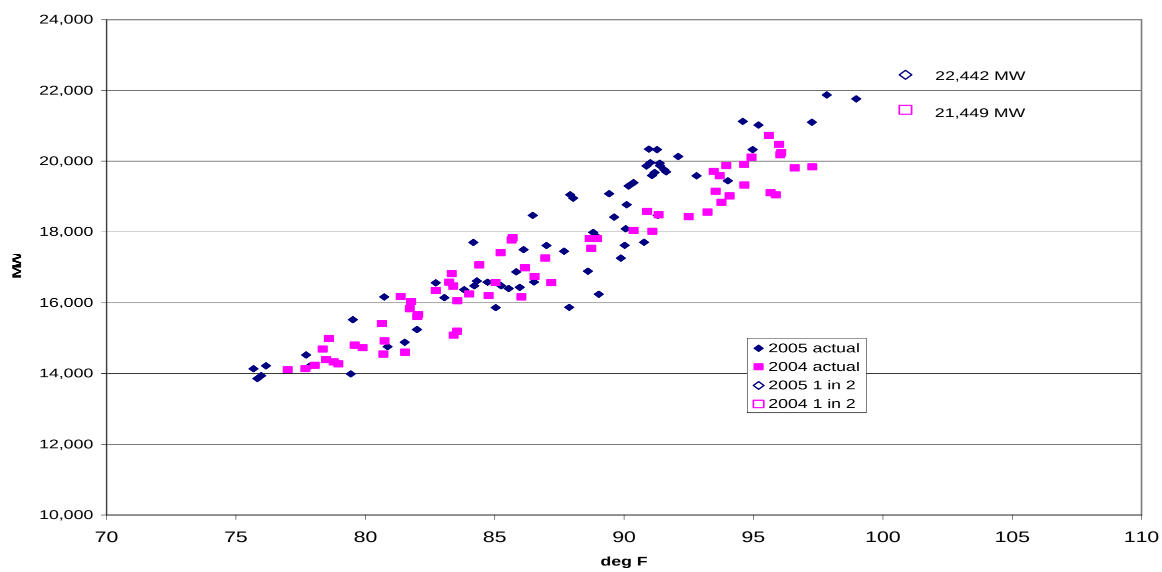
Figure 5 presents 2005 predictions using both temperature (*max631)* and temperature plus the diurnal variation variable (*divar*) as a proxy for humidity. Including *divar* reduces the 2005 weather normalized peak approximately 215 MW over temperature alone. The “normal” diurnal variation (33.55) is defined as the average diurnal variation that occurred at the median SCE peak temperature of 101 deg F over the 1950-2005 period.

Figure 5: Model Results of SCE 2005 Summer Weekday Peak And Weather Variables



Summer weekday peaks for 2004 and 2005 along with the weather normalized peak values for each year are compared (Figure 6). The *divar* variable was used in the weather normalization for both years because it proved to be a significant explanatory variable of weekday peak loads for each year.

Figure 6: SCE 2004 – 2005 Summer Weekday Temperature-Peak Comparison



SDG&E Planning Area Results

The SDG&E planning area analysis used both lagged maximum temperature and daily diurnal variation. Staff also used a combination of Lindberg field, Miramar Naval Air station and El Cajon weather stations to represent the SDG&E planning area, rather than only Lindberg field as has been done in the past. Because staff has no reliable weather information for El Cajon prior to 1979, the time period for historic analysis was limited to 979-2005 to use data from the three weather stations. The weather variables were calculated as an average of the three stations. The regression fit was improved by using both *max631* and *divar* (R^2=0.91) compared to using only *max631* (R^2=0.88) (Figure 7)**.**

Figure 7: Predicted SDG&E Weekday Peaks Using Temperature and Diurnal Variation

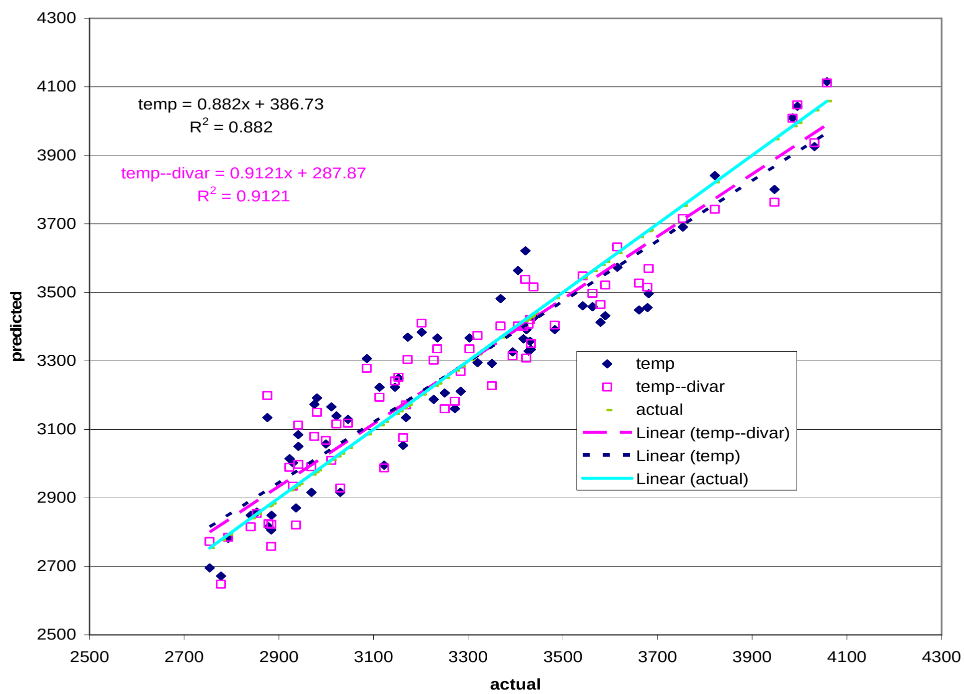
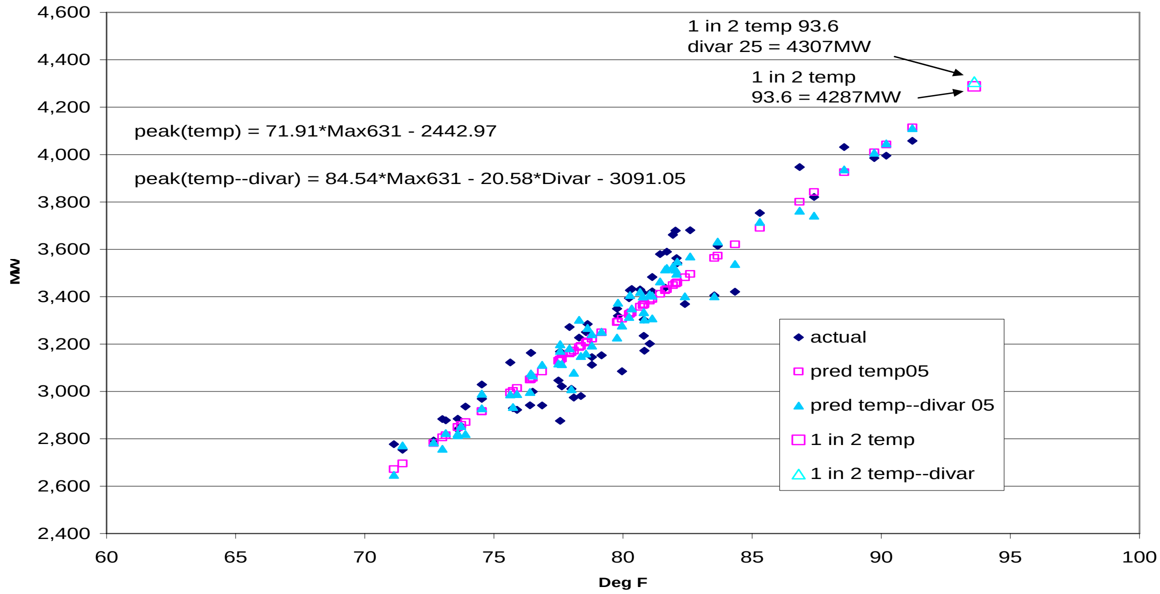


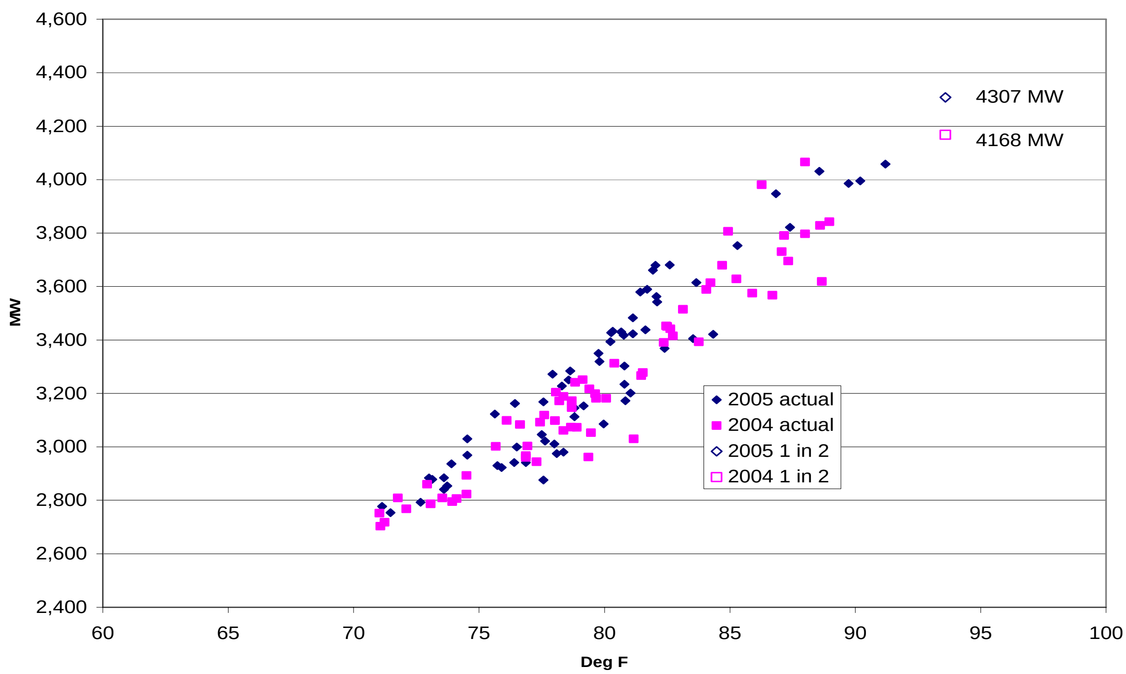
Figure 8 presents the 2005 predictions using both temperature and temperature in combination with the diurnal variation variable. Including the diurnal variation variable in the SDG&E planning area increases the estimates of the weather-adjusted peak approximately 20 MW.

Figure 8: Model Results of SDG&E 2005 Summer Weekday Peak And Weather Variables



Summer weekday peaks and weather normalized values for both 2004 and 2005 are compared in Figure 9.

Figure 9: SDG&E 2004 – 2005 Summer Weekday Temperature-Peak Comparison



Sources of Forecast Error

Staff's initial assessment is that the forecast error was caused at least in part by model assumptions that underestimate the percentage of homes with central air conditioning. Analysis of the 2004 Residential Appliance Saturation Survey (RASS) data is yielding data on the percentage of homes with central air conditioning that, for many climate zones, are significantly higher than those assumed in the September 2005 forecast. The September 2005 forecast used assumptions based on much older survey data; updated saturations from the 2004 RASS were not yet available. The new RASS results suggest that many more existing homes have been retrofit with central air conditioning than assumed by the residential forecast model, particularly in more temperate climates such as the San Jose and Long Beach zones. Underestimating the number of air conditioning units in these areas is likely to have a disproportionate impact on peak demand compared to annual energy use because those units may be used only on the few hot days per year. A more complete analysis of the cause of the forecast error will be done as part of the 2007 *Energy Report* forecast.

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[1] Rulemaking 04-04-003, Decision 05-10-042, October 27, 2005, http://www.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/50731.htm

[2] California Energy Demand 2006-2016 - Staff Energy Demand Forecast - Revised September 2005 - Staff FINAL Report. Publication # CEC-400-2005-034-SF-ED2. , http://www.energy.ca.gov/2005publications/CEC-400-2005-034/CEC-400-2005-034-SF-ED2.PDF

[3] R^2, the coefficient of determination, is a statistical measure of the proportion of variation in the dependent variable (peak demand) which is explained by variation in the independent variables (temperature data).